ACCESSION #: 9403230057
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Calvert Cliffs, Unit 2 PAGE: 1 OF 9

DOCKET NUMBER: 05000318

TITLE: Reactor Trip Due to Opening of 13.8 Kilovolt Feeder Breaker
EVENT DATE: 01/12/94 LER #: 94-001-01 REPORT DATE: 03/16/94

OTHER FACILITIES INVOLVED: CC, Unit 1 DOCKET NO: 05000317

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i), 50.73(a)(2)(iv), 50.73(a)(2)(v)

LICENSEE CONTACT FOR THIS LER:
NAME: R. Cary Gradle, Compliance Engineer TELEPHONE: (410) 260-3738

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On January 12, 1994 at 0552, Calvert Cliffs Unit 2 tripped when an electrical protective relay actuated in the 13.8 kv voltage regulator (2H2103) for Unit Service Transformer (UST) U-4000-22. This actuation caused the loss of 4 kv Busses 22, 23, and Safety Bus 24. Both control element drive mechanism motor generator sets lost power, causing a reactor trip from loss of power to the control element drive assemblies and a main turbine trip.

The cause of the 13.8 kv feeder breakers opening was the actuation of the sudden pressure trip circuit for the 13.8 kv voltage regulators due to intermittent grounds on their associated 125 VDC bus.

A Significant Incident Finding Team was appointed by the Plant General Manager to investigate the event. The results of this investigation and associated corrective actions are included in this supplemental report.

END OF ABSTRACT

I. DESCRIPTION OF EVENT

On January 12, 1994 at 0552, Calvert Cliffs Unit 2 tripped when an electrical protective relay actuated in the 13.8 kv voltage regulator (2H2103) for Unit Service Transformer (UST) U-4000-22. This actuation caused the loss of 4 kv Busses 22, 23, and Safety Bus 24. Both control element drive mechanism motor generator sets lost power, causing a reactor trip from loss of power to the control element drive assemblies and a main turbine trip.

Subsequently, similar protective relaying for UST U-4000-21, which supplies the redundant Unit 1 4 kv Safety Bus 14, actuated resulting in a loss of normal power supply to Bus 14. At the time of the event, both units were operating at 100 percent power.

At the time of the event, a modification was under construction which installs six 13.8 kv voltage regulators (three per Unit). Each regulator has manual transfer switches located between the respective UST 13.8 kv supply feeder breaker and the UST. On the morning of January 12, 1994, all six voltage regulators and transfer switch assemblies were mounted in place, but their 13.8 kv cables were not connected to existing plant equipment. Their annunciation circuits were tagged out with fuses removed. The voltage regulator protective trip circuits to the respective 13.8 kv supply feeder breaker control circuit had been connected earlier in the construction sequence. The project team members incorrectly believed these protective trip circuits were functionally isolated from existing plant equipment. At the time of the event, construction personnel were working on top of Unit 2 voltage regulator 2H2101 and inside each of the three Unit 2 voltage regulator transfer switch assembly cabinets. They were preparing 13.8 kv cable ends for termination during future planned 13.8 kv bus outages.

Each voltage regulator protective circuit consists of two parallel circuits sensing a sudden pressure increase in either of two separate compartments. Each circuit consists of a bellows-type sensor switch and solid-state seal-in relay circuit card which is connected to the trip circuit of the associated 13.8 kv UST feeder breaker. The circuit is designed to open the breaker and deenergize the regulator/transformer combination in the event of a sudden pressure increase from a fault inside a winding compartment.

Figure 1 provides a schematic of the power supply scheme discussed in this Licensee Event Report (LER).

At 0552, a Sudden Pressure Trip Relay actuated in voltage regulator 2H2103, tripping open 13.8 kv feeder breaker (252-2103) to UST U-4000-22. 4 kv Busses 22, 23, and 24 feeder breakers (152-2201, 152-2311, and 152-2401, respectively) also tripped open, as designed, on undervoltage and Unit 2 tripped. Control Room operators implemented appropriate post-trip Emergency Operating Procedures. Auxiliary feedwater flow was initiated at 0556. Emergency Diesel Generator (EDG) 21 started and loaded as designed.

A Plant Watch Supervisor was dispatched to inspect the 13.8 kv electrical components for anomalies. He found UST U-4000-22 feeder breaker 252-2103 open. There was no local indication of any breaker protective devices tripped, but the breaker's lockout device was tripped. The Unit 1 13 kv switchgear house was inspected and all breaker conditions were normal.

At 0617 the 13.8 kv feeder breaker (252-2102) to UST U-4000-21 tripped open, with a subsequent undervoltage trip of Unit 1 4 kv Bus 14 feeder breaker 152-1414. No. 12 EDG started upon loss of power to 4 kv Bus 14. Unit 1 Control Room operators implemented appropriate procedures and took actions to close alternate feeder breaker 152-1401, which reenergized 4 kv Bus 14.

At 0619, the 13.8 kv feeder breaker (252-2101) to UST U-4000-23 tripped open, resulting in a loss of Unit 2 4 kv Busses 25 and 26. At 0628, the Control Room staff had determined that the spurious 13.8 kv breaker trips were isolated to 13.8 kv Bus 21 and opened the 13.8 kv Service Bus 21 feeder breaker 252-2104, deenergizing 13.8 kv Service Bus 21.

At approximately 0630 plant electricians verified a ground on Unit 2 125 VDC Bus 21. Using schematic drawings of the voltage regulator they identified the sudden pressure trip protective circuit, investigated, and found a sudden pressure seal-in relay actuated for each of the three Unit 2 voltage regulators. Subsequent troubleshooting isolated the DC ground to voltage regulator 2H2102. Plant electricians discovered that all three voltage regulator protective trip circuits were connected to the breaker control circuits.

The sudden pressure trip circuits for the breakers associated with the Unit 2 13.8 kv voltage regulators were disconnected. The three Unit 2 voltage regulator transfer switch assemblies were then tagged and locked in the bypass mode.

At 1535, Unit 2 13.8 kv Bus 21 was reenergized. At 1550, the other Unit 2 4 kv busses were restored to a normal lineup. Similarly, Unit 1 4 kv busses

were restored to a normal electrical lineup with the voltage regulators isolated and the trip circuits removed, at about 1845.

II. CAUSE OF EVENT

The immediate cause of the 13.8 kv feeder breakers opening was the actuation of the sudden pressure trip circuit for 13.8 kv voltage regulators due to intermittent grounds on their associated 125 VDC bus. Extensive electrical bench testing confirmed that the circuit would actuate in the presence of a DC ground in the specific condition that the circuit was in at the time. An actuation did not occur if the circuit was in its final designed configuration. The designed circuit is reliable if it is properly connected. However, if the sensor device is disconnected (and a ground occurs), we have shown that the solid-state seal-in relay will actuate. Opportunities were missed to detect the sensitivity of the solid-state seal-in relay during the design review phase of the project.

A Significant Incident Finding Team (SIFT) was appointed by the Plant General Manager to investigate the event. The SIFT determined the actuations were caused by intermittent grounds on the DC control power circuits interacting with the plant's DC ground detection system. The grounds actuated the sensitive solid-state relay because its sensor device was not connected. The intermittent nature of the electrical ground in the system was most likely due to loose leads from a terminal block in the 2H2102 bypass transfer switch cabinet coming into contact with the inner cabinet door. The leads were not taped and minor movement of the door or the leads could have resulted in their contact.

A detailed analysis of this event has identified the following root causes.

A. Our control of new equipment while under construction was less than adequate. The 50.59 safety evaluation required the sudden pressure trip protective circuit to be disabled. This circuit was energized and enabled prematurely. The Design Instructions did not adequately implement the requirements of the 50.59 safety evaluation as required by our modification procedures. This inadequate design control carried through the implementing work package.

B. The modification process did not adequately require testing to be integrated with work in progress. The 50.59 safety evaluation specified the required voltage regulator transfer switches' positions to disable the trip circuit. The voltage regulator bypass

transfer switch auxiliary contacts were assumed, but not verified, to be functional. Sensor devices were not detected disconnected.

C. Less than adequate communications existed between project team members. After many of the project meetings, there were conflicting views of the planned approach to ensure the protective circuits were disabled. Imprecise communications confused 13.8 kv and 125 VDC work and misleading statements existed about "associated DC circuits" and "breaker control wiring."

D. The design review conducted by personnel involved with this modification was less than adequate. The specified sudden pressure increase seal-in relay circuit is susceptible to inadvertent actuation when its sensor is disconnected. The designated method for enabling and disabling the protective circuit (auxiliary switches) was less than adequate. Opportunities were missed by our design personnel to detect the sensitivity of the solid-state seal-in relay during the design review phase of the project.

III. ANALYSIS OF EVENT

A loss of non-emergency AC power (LOAC) event is defined in the Updated Final Safety Analysis Report (UFSAR) as a loss of the plant's 500 kv/13 kv service transformers. A loss of load to one unit's turbine-generator with offsite power unavailable and the other unit's turbine-generator unavailable would result in a LOAC event. In this context, a loss of offsite power (LOOP) means a loss of the main power grid (500 kv ring bus) in conjunction with the loss of the other unit's turbine-generator; in other words, a loss of all non-emergency power with the EDGs supplying AC emergency power to all of the plant's vital electrical loads.

The most limiting LOAC event described in the UFSAR assumes a loss of turbine load on a unit operating at 100 percent power with offsite AC power unavailable and concludes that no significant safety consequences will result from this event. The UFSAR scenario bounds this actual event.

At the time of the event, Unit 1 was fully capable of being safely shutdown and maintained in a safe shutdown condition in the event of a LOOP. No. 12 EDG was OPERABLE and available to provide AC emergency power to Unit 1 safety-related equipment.

At 0405 on January 12, 1994, No. 11 EDG and No. 11 saltwater loop for Unit 1 were removed from service for scheduled maintenance. The next planned 13.8 kv service bus outage for continued modification installation was to occur the following morning on January 13, 1994. Approximately 25 minutes after the start of the event, at 0617, flow was lost through Unit 1 No. 12 saltwater loop when No. 12 saltwater pump stopped due to loss of Unit 1 4 kv Bus 14. Since there is no ACTION statement for two inoperable saltwater loops, Unit 1 was placed in a condition not covered by the plants Technical Specification. Power was promptly restored to 4 kv Bus 14 by closing its alternate feeder breaker, No. 12 saltwater pump was started and saltwater flow was restored through No. 12 saltwater loop. There were no significant safety consequences resulting from the approximately two minutes that flow was lost through No. 12 saltwater loop.

This event is considered reportable under the provisions of the following 10 CFR 50.73 reporting criteria:

A. 50.73(a)(2)(i)(B); Any operation or condition prohibited by the plants Technical Specifications.

B. 50.73(a)(2)(iv); Any event that results in a manual or automatic actuation of any ESF, including the RPS.

C. 50.73(a)(2)(v); Any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems needed to; (b) remove residual heat; and (d) mitigate the consequences of an accident.

IV. CORRECTIVE ACTIONS

Immediate Corrective Actions:

A. The immediate construction areas around the Unit 1 and 2 voltage regulator project were physically posted and quarantined.

B. The Plant General Manager directed that a SIFT assess the event.

C. Each voltage regulator sudden pressure trip circuit was disconnected from its respective 13 kv feeder breaker.

D. The Unit 1 and Unit 2 voltage regulator transfer switch assemblies were tagged and locked in the bypass mode.

E. All work associated with the voltage regulator project that could affect operable plant systems has been stopped, pending Plant General Manager approval.

Preventive Actions:

A. We are currently reviewing the 50.59 safety evaluation, design instructions, and associated implementing procedures for this modification. They will be revised, as necessary, to ensure they are consistent with each other.

B. We are developing an integrated test plan for the 13.8 kv voltage regulator project. The project implementation plan will be presented to the Plant Operations and Safety Review Committee and the Plant General Manager.

C. We will require minutes for project meetings to document concurrence on agreements.

D. We plan to replace the solid-state seal-in relay with a design that is less susceptible to spurious actuation. We plan to remove the auxiliary contacts from the sudden pressure trip circuit and install new test switches.

E. This event has been reviewed with the involved design engineering personnel.

F. We are proceduralizing guidance for review and control of "potential high risk" construction activities.

G. We will develop guidance on how and when to defeat and enable protective circuits.

H. We are developing procedural guidance for integrated work/testing requirements for modifications.

V. ADDITIONAL INFORMATION

A. Affected Component Identification

IEEE 803 IEEE 805
Component or System EIIS Funct System ID

Electrical Protective Relay 94 EA
13.8 kv Voltage Regulator 90 EA
13.8 kv Breaker BKR EA
Motor Generator Sets MG AA
Saltwater System Pump P BI
Emergency Diesel Generator DG EK
125 VDC System N/A EI
Unit Service Transformer XFMR EB

B. Previous Similar Events.

Both LER 50-317/93-003 and this event involve actuation of unnecessarily enabled breaker protection circuits leading to partial losses of offsite power and reactor trips. These events do not have similar casual factors, however. One of the causal factors identified in LER 50-317/93-003 was that isolating the protective circuit was not recognized as a means to avoid an unnecessary reactor trip hazard. In this case, the need to isolate the protective circuit was recognized and planned as part of the modification process. However, in this case, the implementation of the plan did not result in an effective circuit isolation. Thus, while some similarities exist between these events, we have concluded the underlying casual factors of these events are different.

Figure 1 omitted.

ATTACHMENT TO 9403230057 PAGE 1 OF 1

BALTIMORE
GAS AND
ELECTRIC

CALVERT CLIFFS NUCLEAR POWER PLANT
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CHARLES H. CRUSE
PLANT GENERAL MANAGER
CALVERT CLIFFS March 16, 1994

U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 and 2; Docket Nos. 50-317 and 50-318;
License Nos. DPR 53 and DPR 69
Licensee Event Report 94-001, Revision 1
Reactor Trip Due to Opening of 13.8 Kilovolt Feeder
Breaker

The attached supplemental report is being sent to you as required under 10 CFR 50.73 guidelines. Should you have any questions regarding this report, we will be pleased to discuss them with you.

Very truly yours,

CHC/RCG/bjd
Attachment

cc: D. A. Brune, Esquire
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